**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

PETITION FOR MODIFICATION OF DECISION 18-10-019 OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)

JANET S. COMBS
RUSSELL A. ARCHER

Southern California Edison Company
2244 Walnut Grove Avenue
Rosemead, CA 91770
Telephone: (626) 302-2865
Facsimile: (626) 302-3990
E-mail: Russell.Archer@sce.com

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

MARIA V. WILSON
KRISTIN D. CHARIPAR

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-5639
Facsimile: (415) 973-5520
E-mail: Maria.Wilson@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

AIMEE M. SMITH

San Diego Gas & Electric Company
8330 Century Park Court, CP32
San Diego, CA 92123
Telephone: (858) 654-1644
Facsimile: (858) 654-1586
E-mail: amsmith@semprautilities.com

Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

Dated: August 7, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026 (Filed June 29, 2017)

PETITION FOR MODIFICATION OF DECISION 18-10-019 OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)

Pursuant to California Public Utilities Commission (Commission) Rule of Practice and Procedure (Rule) 16.4, and Decision (D.) 20-03-019, Pacific Gas and Electric Company (PG&E) submits this Petition for Modification (PFM) of D. 18-10-019 on behalf of itself, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the Joint Utilities).[1/]

In this petition and the concurrently filed Petition for Modification of D. 17-08-026 in Rulemaking 02-01-011 (collectively, the PFMs) , the Joint Utilities request that the Commission resolve errors in D. 17-08-026 and D. 18-10-019 concerning the application of line losses in the Power Charge Indifference Adjustment (PCIA) calculations. Rule 16.4 (d) requires that a petition for modification filed and served a year after the effective date of a Decision explain why the petition could not have been presented within a year. In lieu of presenting petitions to modify D. 17-08-026 and D. 18-10-019 within a year of issuance of those Decisions, the Joint Utilities sought to address the relevant calculations in Rulemaking (R.) 17-06-026, concerning the reform of the PCIA (PCIA OIR). Ultimately, the Commission considered the Joint Utilities' proposal to address line loss errors in the PCIA OIR and in D. 20-03-019 and decided that a

1/ Pursuant to Rule 1.8(d), PG&E represents that counsel for SCE and SDG&E have authorized PG&E to file this PFM on behalf of their respective organizations.

petition to modify the applicable Commission decisions was the proper procedural vehicle to correct the errors.[2/]

I. SUMMARY OF REQUEST

Through the PFMs, the Joint Utilities seek to correct PCIA calculation errors related to the application of line losses through revisions to formulas contained in attachments to two (2) Commission Decisions. There are two key concerns with the application of line losses. First, the formulas contained in each attachment incorrectly apply line loss adjustments to the Resource Adequacy (RA) component of the PCIA calculation.[3/] Line losses should not apply to the RA value of PCIA-eligible resources because the RA value of a resource is not impacted by line losses. RA is a capacity product, not an energy product; the latter is affected by line losses, not the former. RA value is calculated as the Net Qualifying Capacity (NQC) multiplied by the applicable RA Adders and has no line loss component. Therefore, applying a line loss factor to the RA value is illogical and incorrect.

Second, the PCIA Template adopted by D. 17-08-026 (PCIA Template) presents an inconsistency in its application of line losses with respect to the calculation of energy market value. This inconsistency was acknowledged by the Commission's Energy Division in its disposition of PG&E's Advice 5527-E and 5527 E-B.[4/] Specifically, the PCIA Template utilizes energy volumes at the customer meter as an input to a market value calculation and the energy

---

2/ *See* D. 20-03-019 at Finding of Fact 15 (stating "The Joint IOU PCIA Common Template was originally approved in D. 17-08-026. A petition to modify the decision approving the template is the proper vehicle to have these errors corrected.") and Conclusion of Law 8 (stating "The Joint IOU proposal to remove the line loss factor from the calculations underlying the Power Charge Indifference Adjustment should not be adopted. The IOUs may file a petition to modify the relevant decision.")

3/ Pursuant to Rule 16.4 (b) a Declaration supporting new or changed facts supporting this Petition is provided as Appendix F.

4/ If energy losses are defined as a percentage (i.e., Line Loss Adjustment Factor) of energy delivered at the generator, then energy as measured at the generator meter is calculated as energy delivered at the customer meter divided by one minus the Line Loss Adjustment Factor. The template incorrectly calculates the portfolio value by multiplying the portfolio as measured at the customer meter by one plus the Line Loss Adjustment Factor. This results in an underestimation of the energy attribute market value. This arithmetic error in the template was identified in the Energy Division disposition of Advice 5527-E and 5527 E-B (June 10, 2019) at p. 7, available at https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5527-E-B.pdf.

volumes at the customer meter are derived by scaling down energy volumes measured at the generator meter by 1 minus the Line Loss Adjustment Factor, which is correct. However, in a second step, the PCIA Template grosses up the market value by 1 plus the Line Loss Adjustment Factor to represent market value as delivered at the generation meter, which is mathematically incorrect. This is an unnecessary two-step process that introduces errors. As an example, assume a Line Loss Adjustment Factor of 6 percent; when a number is grossed down by 0.94 and subsequently grossed up by 1.06, the end result is an understated number, or approximately 99.6 percent of what it should be.

The application of line losses to capacity has a larger impact and overstates the portfolio market value. The second issue is a smaller impact where the mathematical inconsistency slightly understates the portfolio's energy market value. The net impact of these two issues is an overstated forecast of portfolio market value with all customers initially underpaying the PCIA. Those customers that underpay the PCIA due to the errors will pay for the resulting under-collection through the true-up, adding to year-to-year PCIA volatility. The Joint Utilities' proposed modifications will eliminate a practice that results in a systematic PCIA under-collection and, ultimately, rate volatility for all customers.

The Joint Utilities respectfully request the Commission remedy the line loss issues through simple revisions to each Decision's Appendix to remove the application of line losses and instead utilize generation-metered volumes in PCIA energy attribute market value calculations.[5/] The Joint Utilities' proposed remedy was chosen for its simplicity. The Line Loss Adjustment Factor can be eliminated because generation-metered volumes are available and can be used directly to calculate energy attribute market values.

The alternative, more complicated, solution would be to continue employing a two-step approach of using customer-metered volumes as an input to calculate energy attribute market

5/ The Joint Utilities only request those revisions relevant to the removal of the Line Loss Adjustment Factor as part of the PFMs and note that further revisions to the PCIA calculation provided as Appendix A to D. 18-10-019 are required to "clean up" the units applicable to the calculation. The Joint Utilities have no concern with the application of units provided in the PCIA Template.

values, correcting the arithmetic error in applying the Line Loss Adjustment Factor to the energy market value attributes, and excluding the application of the Line Loss Adjustment Factor to calculate the capacity market value. Directly using generation-metered volumes, on the other hand, is simpler since it eliminates both the unnecessary two-step process and the arithmetic error.

The Joint Utilities request expedited approval of the PFMs to facilitate the use of accurate PCIA calculations in the November Updates to their respective 2021 Energy Resource Recovery Account (ERRA) Forecast Applications. Expedited approval will allow the Joint Utilities to calculate the PCIA accurately in those November Updates, which will help counteract the systemic rolling PCIA under-collections that are currently accumulating, and which are unnecessarily causing customer rate instability.

II. BACKGROUND

D. 06-07-030 established the PCIA for departing load customers.[6/] The PCIA is calculated by comparing the actual portfolio costs of an IOU's vintaged portfolio to the market value of the IOU's vintaged portfolio. The calculation includes an Energy Index, a Renewables Portfolio Standard (RPS) Adder, and three RA Adders (*i.e.*, system, local, and flexible).[7/] The incorrect application of the line loss factor in the derivation of the PCIA revenue requirement and resulting PCIA rates arises from two Decisions. The Joint Utilities provide a brief overview of the origination of the errors and the attempts to correct those errors prior to filing the PFMs.

A. Decision 17-08-026: Standard Workpaper Template

In D. 16-09-044, the Commission ordered SCE and Sonoma Clean Power Authority (SCP) to lead a Working Group to discuss issues concerning PCIA transparency and forecasting

6/ D. 07-01-030 modified D. 06-07-030 to include a line loss factor for use in the 2007 benchmark calculation.

7/ D. 11-12-018 established that a resource's NQC be used to calculate the capacity value of resources and introduced the RPS Adder. *See also* infra note 13. D.18-10-019 expanded the RA Adder to include three types of RA products.

trends.[8] The Commission ordered the Working Group "to present their recommendations to the Commission either as petitions to modify existing decisions or a petition for a rulemaking proceeding within six months of this Decision."[9]

In April 2017, the Joint Utilities and Community Choice Aggregators (CCAs) jointly filed a petition to modify D. 06-07-030 to include a common set of workpapers for the calculation of the PCIA in the Joint Utilities' respective annual ERRA Forecast Proceeding, and included a common workpaper template as part of that PFM.[10] In D. 17-08-026, the Commission granted the Joint Utilities' and CCAs' request to modify D. 06-07-030 to include the common workpaper template.[11]

The template presented to the Commission in the 2017 PFM of D. 06-07-030 was adopted without modification in D. 17-08-026. That template continued to present non-renewable and renewable generation at the customer meter while the capacity volumes are at the generator. In addition, the template scales output at the generator down by a factor of 1 minus the Line Loss Adjustment (0.94 in PG&E's case) to represent output at the customer meter and grosses the actual market value back up by a factor of 1 plus the Line Loss Adjustment (1.06 in PG&E's case), which is mathematically incorrect. As a result of these inconsistencies, there is an error in the calculation of the portfolio market value. The energy attribute market values (measured at the customer meter) and the RA market value are added together. The Line Loss Adjustment Factor is then incorrectly applied to this sum, both the energy and RA attributes, to create the Line Loss Adjusted Portfolio Market Value.[12] This introduces an error in the

---

8/ D. 16-09-044 at p. 20.

9/ D. 16-09-044 at p. 20 and Ordering Paragraph (OP) 8.

10/ Community Choice Aggregators joining the Petition to Modify D. 06-07-030 with the Joint Utilities comprised of Sonoma Clean Power Authority (SCP), Peninsula Clean Energy (PCE), Silicon Valley Clean Energy (SVCE) and Marin Clean Energy (MCE).

11/ D. 17-08-026 at Finding of Fact 5 (establishing the template as developed by the Joint Utilities and CCAs) and OP 2 (adopting the template).

12/ *See* D.17-08-026, Exhibit A, Page A-3 at line 21 (applying the line loss adjustment to the total portfolio value, which includes the capacity value).

Portfolio Market Value calculation used to calculate the PCIA rate because the capacity value of a resource is based on the NQC of the resource, and is not impacted by line losses.[13/]

B. Decision 18-10-019: Appendix 1

Rulemaking 17-06-026 was opened by the Commission in June 2017 to review, revise, and consider alternatives to the PCIA. Among the topics considered as part of the Rulemaking was the review and possible modification of the PCIA methodology, including the total portfolio input costs and calculation.[14/]

In D. 18-10-019, the Commission adopted revised inputs to the RA and RPS Adders used to calculate the PCIA.[15/] Additionally, D. 18-10-019 adopted revisions to the RA Adder, and established three separate RA Adders for system, local, and flexible RA.[16/] D. 18-10-019 does not consider the addition of line losses to calculate resources' RA value (because the concept of lines losses is inapplicable to capacity). However, Appendix 1 to D. 18-10-019 introduced an error to the Market Price Benchmark (MPB) and Market Value calculation formulas by multiplying the RA Adder and RA Market Value of capacity by the line loss factor. Specifically, Appendix 1 of D. 18-10-019 defines the MPB and Market Value (for vintage year, V) as:

///

///

///

13/ *See* D.11-12-018 at p. 24 (describing the addition to the PCIA of the capacity value of resources based on the resource NQC and not including a line loss adjustment as part of that calculation), at p. 30 (describing the calculation of the RA capacity Adder as based on the NQC of resources in the generation portfolio), and at OP 8 (stating in relevant part that the capacity adder be updated based on the NQC of the resource).

14/ *See* Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment (July 10, 2017) at p. 9.

15/ D. 18-10-019 at Conclusion of Law 3 and 4 (adopting revised RPS and RA Adders as detailed in Appendix 1).

16/ D. 18-10-019 at p.74 (adopting categories of system, flexible, and local RA) and at p. 121 (directing that the RA Adder be calculated based on the type of capacity).

MPB ={(1-RPS%V) x Brown Adder + (RPS% V) x RPS Adder + RA Adder V} x (LOSSES)

Or

Market Value = (Brown Energy V x Brown Adder + RPS Energy V x RPS Adder + NQC V x RA Adder) x (LOSSES)[17/]

The Joint Utilities filed comments on the Proposed Decision of D. 18-10-019, alerting the Commission to the error in the calculation caused by the addition of losses that would result in a systemic under-collection. Specifically, in Opening Comments on the Proposed Decision, the Joint Utilities noted that a potential disparity between forecast energy values and actual market results may be exacerbated by the application of "line losses" to determine the portfolios' market value.[18/] Further, in its Opening Comments on the Alternate Proposed Decision, the Joint Utilities continued to note potential disparities between forecast and actual values in the calculation due to the application of line losses to determine the market value, and stated that the continued incorporation of line losses in the benchmark would result in double-counting, which will then have to be reversed in the true-up.[19/] D. 18-10-019 did not address the Joint Utilities' requests to remove the application of line losses from the calculations contained within Appendix 1, and the adopted calculations contain the erroneous application of losses to the Market Value calculations.

C. Proposals to Correct Line Loss Issue

The Joint Utilities attempted to correct the misapplication of line losses to the PCIA calculations introduced by D. 17-08-026 and D. 18-10-019 following the issuance of D. 18-10-019, and in Phase 2 of R. 17-06-026. Prior to those efforts, PG&E attempted to correct

17/ D. 18-10-019 at Appendix 1.

18/ R. 17-06-026, Joint IOU Opening Comments on Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology (August 21, 2018) at p. 6.

19/ R. 17-06-026, Joint IOU Opening Comments on Alternate Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology (September 6, 2018) at p. 13.

the misapplication of line losses in the common template in PG&E's 2018 ERRA Forecast proceeding.[20]

1. PG&E's 2018 ERRA Forecast Proceeding

When preparing PG&E's November Update submitted as part of its 2018 ERRA Forecast proceeding, PG&E discovered that the common workpaper template approved in D. 17-08-026 to calculate the PCIA contained mathematical errors in its application of line losses. PG&E proposed a method to correct the misapplication of line losses in its November Update submittal.[21] At the request of Energy Division, PG&E was asked to resubmit its PCIA workpapers using the standard template as approved in D.17-08-026. In its decision approving PG&E's 2018 ERRA Forecast, the Commission rejected PG&E's proposal concerning line losses, and required PG&E to use the common workpaper template.[22]

2. Rulemaking 17-06-026

As described above, the Joint Utilities provided comments concerning line loss errors in their comments to the Proposed and Alternate Proposed Decisions resulting in D. 18-10-019. Following the issuance of D. 18-10-019, the Joint Utilities attempted to correct the misapplication of lines losses as part of the ongoing R. 17-06-026. First, the Joint Utilities attempted to address the line loss errors in communications with the Commission's Energy Division served to parties to R. 17-06-026 related to compliance with Ordering Paragraph (OP) 3 of D. 18-10-019. OP 3 required the IOUs to meet and confer concerning a uniform common PCIA template for submittal to the Energy Division. Second, the Joint Utilities attempted to correct the line loss issues as part of the Working Group structure formed to inform Phase 2 of the Rulemaking.

20/ Application (A.) 17-06-005.

21/ *See* D. 18-01-009 at p. 14 (rejecting PG&E's proposal to revise the PCIA common template for the correct application for line losses).

22/ D. 18-01-009 at Conclusion of Law 2.

a. Communications in Compliance with D. 18-10-019

The Joint Utilities sought direction from Energy Division on how to resolve common template errors as part of the uniform common PCIA template compliance submittal following D. 18-10-019. On October 22, 2018, each IOU submitted its common PCIA template to Energy Division pursuant to OP 3 of D. 18-10-019.[23/] As a starting point, the Joint Utilities utilized the common PCIA template adopted in D. 17-08-026.[24/] However, as described above, the PCIA Workpaper Template approved in D. 17-08-026 does not properly apply the line loss factor in the calculation of the market value.

Each utility notified Energy Division and the PCIA service list of the errors contained in the template adopted by D. 17-08-026 and in the Appendix 1 calculation adopted by D. 18-10-019 concerning the application of the line loss factor.[25/]

On October 31, 2018, PG&E submitted a revision to its common PCIA template and identified errors resulting from the application of line losses, and requested Energy Division guidance on the appropriate path for resolution, stating:

> "Applying the line loss adjustment to the RA value overstates the RA value and incorrectly understates the indifference amount by approximately $22 million, based on the portfolio data and market price benchmarks included with the template. All three IOUs identified this calculation error in the documentation that accompanied their respective template submissions on October 22, 2018. As previously requested, the Joint Utilities are seeking guidance from Energy Division on how to correct this error in the standard template.[26/]"

23/ D. 18-10-019, OP 3: "Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall meet and confer to develop a uniform common spreadsheet template for the calculation of each of their PCIA rates and submit it to Energy Division within ten days of the effective date of this order."

24/ D. 18-10-019, fn. 16.

25/ PG&E's October 22, 2018 e-mail communication and narrative attachment is attached as Appendix C and PG&E's October 31, 2018 email communication is attached as Appendix D. In PG&E's October 22, 2018 email, PG&E sought to correct the line loss error in its proposed template.

26/ PG&E's E-Mail on Revision to PG&E's Common Template Pursuant to D. 18-10-019, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment, Served to R. 17-06-026 on October 31, 2018, and attached as Appendix D.

b. Rulemaking 17-06-026: Phase 2, Working Group One

Following guidance provided by Energy Division in 2019, the Joint Utilities sought to correct the line loss errors as part of Phase 2 of the PCIA Proceeding. D. 18-10-019 determined that a second phase of the proceeding would be opened in order to establish a "working group" process to enable parties to further develop proposals for consideration by the Commission. PG&E and the California Community Choice Association (CalCCA) were designated Co-Leads of Working Group One, which comprised of twelve (12) issues concerning the methodologies to calculate and true-up the PCIA, and load forecast and bill presentation issues.[27/]

In the Commission's June 10, 2019 approval of PG&E's Advice Letters 5527-E and 5527 E-B implementing PG&E's 2019 ERRA Forecast revenue requirement in compliance with D. 19-02-023, the Energy Division encouraged PG&E and CCA parties to address an issue related to the PCIA Template in Phase 2 of the PCIA OIR.[28/] Following this direction, PG&E, as Co-Lead to Working Group One, sought to address the line loss issues as part of the Working Group process concerning Working Group One, Issues 8-12. The Final Report of Working Group One, Issues 8-12 was to be submitted to the Commission on July 1, 2019.

As part of the Working Group One process, parties served informal comments and all such informal comments were included as part of the Final Report of Working Group One, Issues 8-12 filed and served to the Commission. The Joint Utilities proposed resolution of the line loss issues identified in the common PCIA template appended to D. 17-08-026 and Appendix 1 to D. 18-10-01 in Informal Comments served to the R. 17-06-026 parties on June 21,

27/ Phase 2 Scoping Memo (February 1, 2019).

28/ Energy Division disposition of Advice 5527-E and 5527 E-B (June 10, 2019) at p. 7, available at https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5527-E-B.pdf (stating "[A]s PG&E describes in its response to the Joint CCA protest of 5527-E-A, the mismatch of the application of line losses occurs within the standard template. PG&E appropriately applies the line loss adjustment to generation values at the generator to describe the amount of power delivered at the customer meter. Subsequently, PG&E applies the 1.06 line loss factor as ordered by D. 17-08-026. Though there is a mismatch, and this likely constitutes an arithmetic error, PG&E has performed the calculation as has been ordered by the Commission. Energy Division strongly encourages both parties to address this line loss issue in R. 17-06-026 Phase 2.")

2019. The Joint IOUs' informal comments were appended as Exhibit B to the Final Report of Working Group One, Issues 8-12. Specifically, the Joint IOUs proposed that:

> "The simplest and most efficient way to correct the two (2) line loss errors is to simply drop the application of the line loss factor from the Template's indifference calculation and reflect generation volumes at the generator meter, rather than at the customer meter. Specifically, the forecasted resource energy of the PCIA portfolio measured at the generator would be included as the inputs to the Common Template.
>
> Elimination of the errors will help to minimize the subsequent PCIA true-up. Finally, both the market revenue forecast and the resource cost forecast would be based on the same energy value as measured at the generator.[29/]"

Concurrent with the submittal of the Final Report of Working Group One, Issues 8-12, PG&E and CalCCA filed a joint motion for additional comment opportunity and to extend time to request evidentiary hearings related to the Final Report of Working Group One, Issues 8-12 (Joint Motion) to facilitate full record development.[30/] The Joint Motion was granted, providing opening and reply commenting opportunities.[31/]

The Joint Utilities utilized the additional Working Group One commenting opportunities to advocate that the Commission remedy PCIA calculation line loss errors in Phase 2 of the PCIA proceeding. In Opening Comments, the Joint Utilities rearticulated their request that the Commission address the line loss as part of the scope of Working Group One, which was intended to make refinements to the PCIA.[32/] The Joint Utilities maintained that "the simplest and most efficient way to correct the two (2) line loss errors is to simply drop the application of the line loss factor from the template's indifference calculation and reflect generation volumes at

---

29/ Joint Informal Comments of PG&E, SCE, and SDG&E on the June 7, 2019 Working Group One Workshop of Phase 2 Working Group One (June 21, 2019) appended to the July 1, 2019 Working Group One, Issues 8-12 Final Report at pages B-28 and B-29.

30/ Joint Motion of PG&E and CalCCA to Amend Scoping Memo (July 1, 2019) at pp. 1-2.

31/ R. 17-06-026 Administrative Law Judge Ruling Modifying Procedural Schedule (July 9, 2019).

32/ Joint Opening Comments of PG&E, SCE, and SDG&E on Working Group One, Issues 8-12 Final Report at pp. 6-7. [hereinafter WG One Opening Comments].

the generator meter, rather than at the customer meter to eliminate both of the line loss application errors and simplify the template."[33/] This correction would " ensure that all calculated Portfolio Market Values and Indifference Amounts within the PCIA template are not impacted by any erroneous applications of the line loss factor."[34/]

The Joint IOU Reply Comments outlined the simplicity of their proposal to eliminate the line loss factor, stating:

"The line loss factor can be eliminated because the generation-metered volumes for IOUs' resources are readily available as part of the IOUs' ERRA forecast application. Generation-metered volumes would be used directly to calculate market value, instead of employing the Template's current two-step approach of using customer-metered volumes to calculate the market value and then grossing up the market value by a line loss factor. Direct use of the generation-metered volumes eliminates the two errors and simplifies the Template.[35/]"

Ultimately, the Commission issued D. 20-03-019 to resolve matters presented to it related to Working Group One, Issues 8-12. The Decision recognized parties' need for more time and opportunity to review the corrections proposed to correct PCIA template errors and determined a "a petition to modify the decision approving the template is the proper vehicle to have these errors corrected."[36/]

III. PROPOSED MODIFICATIONS TO D. 17-08-026 AND D. 18-10-019

To resolve the line loss errors contained within the Appendices to D. 17-08-026 and D. 18-10-019, the Joint Utilities recommend that the line loss factor be removed from the indifference calculations and that generation energy volumes be used to calculate the PCIA.

33/ *Id.*

34/ WG One Opening Comments at p. 7.

35/ Joint Reply Comments of PG&E, SCE, and SDG&E on Working Group One, Issues 8-12 Final Report at p. 5.

36/ D. 20-03-019 at p. 23.

As described herein, the current format of the PCIA Workpaper Template approved in D. 17-08-026 does not properly apply the Line Loss Adjustment Factor, introduces two errors and erroneously calculates a portfolio market value that is too high. The formulas included as Appendix 1 to D. 18-10-019 also improperly include a line loss factor to calculate the market value of capacity.

The Joint Utilities' proposed resolution is simple: elimination of the line loss factor completely from the calculations provided in Appendix 1 to D. 17-08-026 and Appendix 1 to D. 18-10-019. The line loss factor can be eliminated because the generation-metered volumes for IOUs' resources are readily available as part of the IOUs' ERRA forecast applications. Generation-metered volumes would be used directly to calculate market value, instead of employing the PCIA Template's current two-step approach of using customer-metered volumes to calculate the market value and then grossing up the market value by a line loss factor. Direct use of the generation-metered volumes eliminates the two errors and simplifies the Template.

These modifications will result in a correctly calculated market value for the total portfolio indifference calculations. To effectuate this change, the Joint Utilities include a modified Template as Appendix A to the PFMs to replace Appendix 1 to D. 17-08-026 and a modified PCIA formula as Appendix B to the PFMs to replace Appendix 1 to D. 18-10-019.[37/] The Joint Utilities also propose the following wording modifications to D. 17-08-026 and D. 18-10-019 to effectuate the necessary corrections.

A. D. 17-08-026

In order to address the line loss error, in the concurrently filed Petition to Modify D. 17-08-026 in Rulemaking 02-01-011, the Joint Utilities respectfully request the Commission modify D. 17-08-026 with the following changes.

37/ A redline of the Joint Utilities' proposed template, compared to the current template in effect is also included as Appendix E.

Findings of Fact

5. Joint Utilities and CCAs request that the Commission adopt the workpaper template (Appendix A) and modify the language of D. 06-07-030 to implement the workpaper requirements. The Joint Utilities request that the workpaper template be updated to remove the erroneous application of line losses to capacity volumes and to instead utilize energy volumes as measured at the generator meter.

Conclusions of Law

1. It is reasonable to modify D. 06-07-030 as proposed in Joint Utilities' and CCAs' Joint Petition for Modification filed on April 5, 2017 with updates to Appendix A to remove the application of line losses proposed in the Joint Utilities' Petition for Modification filed on August 7, 2020.

Order

2. The workpaper template attached to this decision as Appendix A is attached to Decision 06-07-030 as Appendix ~~7~~ 8.

3. Decision 06-07-030, Finding of Fact 28, at page 53, is modified to read:

28. The parties' proposal to replace the DWR power charge with a PCIA is a reasonable way to preserve the indifference concept. In order to improve the transparency of the calculation underlying the PCIA, the IOUs are directed to use a common PCIA calculation workpaper template in their respective ERRA Forecast proceedings. An example of that template is attached hereto as Appendix ~~7~~ 8. [The underlined portion is the additional language approved by this decision as modified by the Joint Utilities Petition for Modification to remove the application of line losses from the workpaper template.]

B. D. 18-10-019

In order to correct the line loss error, the Joint Utilities respectfully request that the Commission modify D. 18-10-019 with the following changes, as modified by D. 20-01-030.

Findings of Fact

4. A revised RA Adder that is calculated using reported purchase and sales prices of IOU, CCA, and ESP transactions will produce reasonably accurate estimates, if a zero or de minimis price is assigned for capacity expected to remain unsold. In order to improve the accuracy of the PCIA calculation, the IOUs are directed to remove the application of line losses to the capacity calculation.

Conclusions of Law

4. The methodology for calculating the RA Adder adopted in D. 06-07-030 and modified in D. 07-01-030 should be changed to the method provided in Appendix 1 of this decision, with energy measured at the generator meter.

IV. CONCLUSION

The Joint Utilities request that the Commission expeditiously issue a decision approving the proposed modifications to Appendix 1 to D. 17-08-026 and Appendix 1 to D. 18-10-019, in accordance with the Joint Utilities' request.

Respectfully Submitted,

MARIA V. WILSON
KRISTIN D. CHARIPAR

By: */s/ Maria V. Wilson*
MARIA V. WILSON

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-5639
Facsimile: (415) 973-5520
E-Mail: Maria.Wilson@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY
on behalf of the Joint Utilities

Dated: August 7, 2020

Appendix A

IOU Total Portfolio Summary

XXXX ERRA Forecast

Incremental by Year	CTC-Eligible	Legacy UOG	Vintage Portfolios 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
1. CRS Eligible Portfolio Costs ($000)														
2. CRS Eligible Non-Renewable Supply at Generator Meter (GWh)														
3. CRS Eligible Renewable Supply at Generator-Meter (GWh)														
4. CRS Eligible Total Net Qualifying Capacity (MW)														
5. CRS Eligible System NQC (System only, No flex or local)														
6. CRS Eligible Local NQC (System and local, with or without flex)														
7. CRS Eligible Flexible NQC (System and flex only, No local)														

Indifference Calculation Inputs and Sources

XXXX ERRA Forecast

Line No.	Description	Source of Data	Value
1.	On Peak NP 15 Price ($/MWh)	Platt's	
2.	Off Peak NP 15 Price ($/MWh)	Platt's	
3.	On Peak Load Weight (%)	XXXX Recorded Load - On Peak Hours	
4.	Off Peak Load Weight (%)	XXXX Recorded Load - Off Peak Hours	
5.	Load Weighted Average Price ($/MWh)	Line 1 x Line 3 + Line 2 x Line 4	
6.	REC Benchmark ($/MWh)	Energy Division	
7.	Total "Green" Benchmark ($/MWh)	Line 6 + Line 5	
8.	System RA Benchmark ($/kW-Year)	Energy Division	
9.	Local RA Benchmark ($/kW-Year)	Energy Division	
10.	Flexible RA Benchmark ($/kW-Year)	Energy Division	
11.	Franchise Fees and Uncollectibles Factor	[GRC Decision / Advice Letter Reference]	

Indifference Amount Calculation

XXXX ERRA Forecast

Line No.	Description	Equation	Unit	CTC-Eligible	Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Cost of Portfolio															
1.	CRS Eligible Portfolio Costs	Portfolio Summary Line 1	$000													
2.	CRS Eligible Non-Renewable Supply at Generator Meter	Portfolio Summary Line 2	GWh													
3.	CRS Eligible Renewable Supply at Generator Meter	Portfolio Summary Line 3	GWh													
4.	CRS Eligible System NQC	Portfolio Summary Line 5	MW													
5.	CRS Eligible Local NQC	Portfolio Summary Line 6	MW													
6.	CRS Eligible Flexible NQC	Portfolio Summary Line 7	MW													
7.	**Portfolio $/MWh Cost**	**Line 1 / (Line 2 + Line 3)**	**$/MWh**													
8.	**Market Value of Portfolio**															
9.	**Market Value of Brown Portfolio**															
10.	Non-Renewable Energy	Line 2	GWh													
11.	Platt's Weighted Price (Brown Benchmark)	Input Line 5	$/MWh													
12.	**Market Value of Brown Portfolio**	**Line 10 x Line 11**	**$000**													
13.	**Market Value of Green Portfolio**															
14.	Renewable Energy	Line 3	GWh													
15.	Weighted Average Green Benchmark	Input Line 7	$/MWh													
16.	**Market Value of Green Portfolio**	**Line 14 x Line 15**	**$000**													
17.	**Capacity Adder**															
18.	Average Monthly System NQC	Line 4	MW													
19.	System RA Benchmark	Input Line 8	$/kW-Year													
20.	Average Monthly Local Area NQC	Line 5	MW													
21.	Local RA Benchmark	Input Line 9	$/kW-Year													
22.	Average Monthly Flexible NQC	Line 6	MW													
23.	Flexible RA Benchmark	Input Line 11	$/kW-Year													
24.	**Market Value of Capacity**	**Sum (Lines 18 x 19, 20 x 21, 22 x 23)**	**$000**													
25.	**Portfolio Market Value**	**Line 12 + Line 16 + Line 24**	$000													
26.	**Indifference Amount**															
27.	**Portfolio Total Cost**	**Line 1**	$000													
28.	**Portfolio Market Value**	**Line 25**	$000													
29.	**Total Indifference Amount (Unadjusted)**	**Line 27 - Line 28**	$000													
30.	**DWR Revenue Requirement**		$000													
31.	**One-Time Adjustments (if applicable)**[1/]		$000													
32.	**PABA Year-End Balance**		$000													
33.	**Vintaged PABA Revenue Requirement**	**Sum (Lines 29:32)**	$000													
34.	**Vintaged PABA Rev Req with FF&U**	**Line 33 x Input Line 11.**														

1/ One-Time Adjustment - Note to provide detail

Indifference Rate Calculation
XXXX ERRA Forecast

			CTC RRQ	Indifference Amount w/o CTC Allocated to Rate Group -- Total Indifference RRQ by Vintage x Column C											
Rate Group	Total Billing Determinants (kWh)	Generation Allocation	All	Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Ongoing															
BA Amortization															
Total RRQ															
Residential															
Small L&P															
Medium L&P															
E19															
Streetlights															
Standby															
Agriculture															
E20 T															
E20 P															
E20 S															
Total	-														

Rate Group	Forecast Sales of Those Responsible for Each Portfolio of Resources (GWh)												
	CTC Sales	Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential													
Small L&P													
Medium L&P													
E19													
Streetlights													
Standby													
Agriculture													
E20 T													
E20 P													
E20 S													
Total Sales													

	CTC Rate	Incremental Rate for Each Portfolio of Resources (Vintage Indifference Amount by Rate Group / Forecast Sales by Rate Group)											
Rate Group	All	Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential													
Small L&P													
Medium L&P													
E19													
Streetlights													
Standby													
Agriculture													
E20 T													
E20 P													
E20 S													
Total													

Indifference Rate Calculation
XXXX ERRA Forecast

Rate Group	CTC Rate All	Cumulative Rate for Each Portfolio of Resources (Vintage Indifference Amount by Rate Group / Forecast Sales by Rate Group) 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential												
Small L&P												
Medium L&P												
E19												
Streetlights												
Standby												
Agriculture												
E20 T												
E20 P												
E20 S												
Total												

DWR Franchise Fee (All) = $ 0.00004

Rate Group	CTC Rate All	Cumulative PCIA Rate with DWR Franchise Fee 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential												
Small L&P												
Medium L&P												
E19												
Streetlights												
Standby												
Agriculture												
E20 T												
E20 P												
E20 S												
System Average Rate												

Rate Model - Check	PG&E Rates from Billing Table												
Rate Group	CTC	Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential													
Small L&P													
Medium L&P													
E19													
Streetlights													
Standby													
Agriculture													
E20 T													
E20 P													
E20 S													

	Difference											
Rate Group	CTC	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential												
Small L&P												
Medium L&P												
E19												
Streetlights												
Standby												
Agriculture												
E20 T												
E20 P												
E20 S												

Note: Difference +/- of $0.00001 / kWh is due to rounding.

Cost Responsibility Surcharge (CRS) Rates

XXXX ERRA Forecast

Rate Group	DWR Bond (All Vintages)	ECRA (All Vintages)	CTC (For All Vintages)	Proposed PCIA Rates by Vintage 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential														
Small L&P														
Medium L&P														
E19														
Streetlights														
Standby														
Agriculture														
E20 T														
E20 P														
E20 S														
System Average PCIA Rate by Vintage														

Appendix B

Appendix 1 (Revised)

Revised Formula for the Power Cost Indifference Adjustment (PCIA) Market Price Benchmark (MPB)

Definition of Terms:

- BROWN = Brown Power Index
- RPS = RPS Adder
- RA = RA Adder
- n = PCIA forecast year covered by the calculation (e.g. n=2020 for the MPB for 2020 forecast year)
- v = PCIA vintage year
- NQC = Net Qualifying Capacity (MW)

Adopted Formula:

The MPB for year n and Vintage Total Portfolio V

= { (1-RPS%V) x Brown Adder + (RPS% V) x RPS Adder + RA Adder V }

Market Value V = MPB V x (Brown Energy V + RPS Energy V)

Or

Market Value V = (Brown Energy V x Brown Adder + RPS Energy V x RPS Adder + NQC V x RA Adder)

Data Sources

1. Brown Power Index ($/MWh) = Weighted average of peak and off-peak forward prices for year n, weighting based on, for each IOU, the IOU bundled load profile data for the most recent year that is publicly available. Peak and off-peak forward prices based on published data for NP15/SP15 pursuant to D.06-07-030
2. RPS Adder ($/MWh) = weighted average of RPS procurement costs excluding RA value from all Load Serving Entities (LSEs) for purchase and sales transactions in year n-2, reported in year n-1 and trued-up in year n+1.
3. RA Adder ($/KW-year) = weighted average of system, local and flexible RA prices from all Load Serving Entities (LSEs) for purchases and sales transactions in year n-2 as published in the annual RA report by the Commission's Energy Division

End of Appendix 1

Appendix C

From: Wu, Josephine
Sent: Monday, October 22, 2018 5:06 PM
To: KHernandez@Pico-rivera.org; AAlstone.Cal@RedwoodEnergy.org; BabBoswell@yahoo.com; beth@cal-cca.org; john.leslie@dentons.com; KMorris@HermosaBch.org; MSkolmik@ceo.LACounty.gov; matthew@turn.org; TomH@SVCleanEnergy.org; GSyphers@SonomaCleanPower.org; MNordlicht@AgeraEnergy.com; BFarnsworth@PalmcoEnergy.com; Carolyn.Berry@BatesWhite.com; Compliance@LibertyPowerCorp.com; bsmith@tigernaturalgas.com; JLunday@tnsk.com; angela.gregory@edftrading.com; aundrea.williams@GexaEnergy.com; TBardacke@CleanPowerAlliance.org; kb@YepEnergy.com; Gregory.Kosier@Constellation.com; Douglass@EnergyAttorney.com; Russell.Archer@SCE.com; Ty@TosdalLaw.com; ty@tosdallaw.com; FOrtlieb@SanDiego.gov; Greg.Bass@CalpineSolutions.com; Jane@ucan.org; TDarton@PilotPowerGroup.com; amsmith@semprautilities.com; KBarrows@cvag.org; kantobam@applevalley.org; RBishop@WRCOG.us; cDeFalco@CityofLancasterCa.org; doug@clean-coalition.org; MBuckner@AdamsBroadwell.com; BHale@SFWater.org; Folk@SMWlaw.com; cc2@cpuc.ca.gov; shelby@brightlinedefense.org; malcantar@buchalter.com; NSheriff@buchalter.com; EKahl@Buchalter.com; Scott.Olson@DirectEnergy.com; BCragg@GoodinMacBride.com; JArmstrong@GoodinMacBride.com; mday@goodinmacbride.com; PatrickFerguson@dwt.com; PatrickFerguson@dwt.com; Fogelson, Matt (Law) <MAFv@pge.com>; Christian_Lenci@Praxair.com; jeremy.weinstein@pacificorp.com; Mark.Byron@UCOP.edu; TLindl@kfwlaw.com; service@cforat.org; NMalcolm@MCEcleanEnergy.org; Ken@350BayArea.org; Jeanne.Sole@SanJoseCa.gov; SShupe@SonomaCleanPower.org; Danielle@RenewableEnergyStrat.com; CMKehrein@ems-ca.com; peffer@braunlegal.com; NSaracino@WEAWLaw.com; Blaising@BraunLegal.com; Blaising@BraunLegal.com; RL@eslawfirm.com; Tim@LargeScaleSolar.org; KMills@cfbf.com; Cynthia.Hansen@PacifiCorp.com; Saleba@EESConsulting.com; YLu@SanDiego.gov; ahoekstra@hanoverstrategyadvisors.com; Alia.Schoen@BloomEnergy.com; Brian.Theaker@NRG.com; RegRelCPUCCases <RegRelCPUCCases@pge.com>; Chris_King@Siemens.com; CHooven@sandiego.gov; Gutierrez, David <D1G9@pge.com>; diana.mahmud@gmail.com; DVawter@Terra-Gen.com; regulatory@ebce.org; EBeaver@SempraUtilities.com; EmilySangi@dwt.com; GChapjian@co.santa-barbara.ca.us; hanna.grene@energycenter.org; JCregar@co.santa-barbara.ca.us; Hilgart, Jessica <JKHh@pge.com>; KCameron@Buchalter.com; KatieJorrie@dwt.com; Kavya@NewsData.com; komidiji@semprautilities.com; Keith@KDWhiteConsulting.com; kjsimonsen@ems-ca.com; lettenson@nrdc.org; Laura.Genao@sce.com; lgoldberg@ebce.org; Michelle.Stark@sce.com; NReardon@SonomaCleanPower.org; Paul@BarkovichAndYap.com; RCavanagh@nrdc.org; roger@berlinerlawpllc.com; sephra.ninow@energycenter.org; sswaroop@mceCleanEnergy.org; Sharon.Yang@libertyutilities.com; Sumeeta.Ghai@EnergyCenter.org; tmarrinan@hanoverstrategyadvisors.com; TEdmister@ebce.org; VidhyaPrabhakaran@dwt.com; regulatory@mcecleanenergy.org; team@cameron-daniel.com; mrw@MRWassoc.com; JMcMahon@CRAi.com; edwin@newtyn.com; SRantala@EnergyMarketers.com; Brandon@CommunitySolarAccess.org; CPUCdockets@EQ-Research.com; MBrubaker@Consultbai.com; Edward.Ross@DirectEnergy.com; CGoodman@EnergyMarketers.com; MLanger@CleanPowerAlliance.org; NKeefer@CleanPowerAlliance.org; Lujuana.Medina@energyRSC.com; Dan.Marsh@libertyutilities.com; Klatt@EnergyAttorney.com; Amy.Liu@sce.com; Case.Admin@sce.com; Desiree.Wong@sce.com; steven.w.coulter@sce.com; Janet.Combs@sce.com; CNajera@EncinitasCa.gov; KBrust@encinitasCa.gov; TBoerner@EncinitasCa.gov; Angela@TosdalLaw.com; ChadColtonLaw@gmail.com; ARosia@SanDiego.gov; Ry.Rivard@VoiceOfSanDiego.org; tbrill@sempra.com; liddell@energyattorney.com; profrmh53@gmail.com; Courtney@ucan.org; Eric@Strategyi.com; KaatzJ-11@SanDiego.edu; marcie.milner@shell.com; Regulatory@PilotPowerGroup.com; BHenzie@SempraUtilities.com; CSummers@SempraUtilities.com; DAKinports@SempraUtilities.com; DNiehaus@SempraUtilities.com; GBarnes@SempraUtilities.com; JWright@SempraUtilities.com; SPate@Sempra.com;

SSidhar@SempraUtilities.com; SVanGoor@SempraUtilities.com; KGill@semprautilities.com; SWadalawala@TeaInc.org; Steven.DeBaun@BBKLaw.com; BSpoonhour@WRCOG.us; Ryan.Baron@BBKLaw.com; Ryan.Baron@bbklaw.com; rshilling@krcd.org; JPepper@PeninsulaCleanEnergy.com; JWaen@PeninsulaCleanEnergy.com; Sue.Mara@RTOadvisors.com; JWiedman@PeninsulaCleanEnergy.com; mdjoseph@adamsbroadwell.com; MMaurino@AdamsBroadwell.com; rkoss@adamsbroadwell.com; robertearle.sf@gmail.com; Hilary.Staver@SVCleanEnergy.org; poonum.agrawal@svcleanenergy.org; Safdi@SMWlaw.com; suzy.hong@sfcityatty.org; brc@cpuc.ca.gov; kb1@cpuc.ca.gov; Eddie@BrightlineDefense.org; Docket@Buchalter.com; Middlekauff, Charles (Law) <CRMd@pge.com>; EOlson@aee.net; Brown, Erica <e1ba@pge.com>; Wu, Josephine <JWWd@pge.com>; Charipar, Kristin (Law) <KDCI@pge.com>; LKoehler@edf.org; Hudson, Lauren <LDRi@pge.com>; Wilson, Maria Vanko <MNVA@pge.com>; Mark.Fillinger@FirstSolar.com; Gonzales, Matthew <MRGg@pge.com>; MCade@Buchalter.com; Ek-Info@Buchalter.com; Jarman, Thomas <TAJ8@pge.com>; ASpringgate@Buchalter.com; LRafii@Buchalter.com; Brian@ohmConnect.com; Buck.Endemann@KLGates.com; MSomogyi@GoodinMacBride.com; tara.kaushik@hklaw.com; TSolomon@Winston.com; TAS@TASStrategies.com; DWTcpucDockets@dwt.com; jkarp@winston.com; steven@moss.net; Post, Jennifer <JLKm@pge.com>; MeganMMyers@yahoo.com; SSMyers@att.net; leora@cal-cca.org; service@spurr.org; Avis.Kowalewski@Calpine.com; BarmackM@calpine.com; April.Sommer@ProtectOurCommunities.org; Sarah.Qureshi@NextEraEnergy.com; AHarron@HarronLLC.com; allie.detrio@engie.com; Cynthia.Clark@UCOP.edu; MBrandt@ebce.org; Barbara@BarkovichAndYap.com; Katherine.Ramsey@SierraClub.org; RBird@BorregoSolar.com; SPauker@kfwlaw.com; Patrick.Vanbeek@CommercialEnergy.net; ron.perry@CommercialEnergy.net; DMarcus2@sbcGlobal.net; cesa_regulatory@storagealliance.org; Michelle@Common-Spark.com; Louise.Dyble@gmail.com; NRader@Calwea.org; PhilM@SCDenergy.com; JNA@speakeasy.org; woody@climateprotection.org; cbhall@sonomacleanpower.org; ACampbell@RedwoodEnergy.org; DHou@caiso.com; JPinjuv@caiso.com; rs@rkas-ca.com; AHartmann@SWMconsult.com; Chase.Hopkins@sen.ca.gov; Griffiths@BraunLegal.com; jw3@cpuc.ca.gov; Joshua.Nelson@bbklaw.com; Wynne@BraunLegal.com; kdw@woodruff-expert-services.com; Taylor@BraunLegal.com; Regulatory@BraunLegal.com; Sarah.Kozal@Stoel.com; SMN@dwgp.com; Steven@IEPA.com; ABB@ESLawfirm.com; bsb@eslawfirm.com; Andrew.Meditz@smud.org; atrowbridge@daycartermurphy.com; rnevis@daycartermurphy.com; Margaret.Miller@Avangrid.com; Cathie.Allen@PacifiCorp.com; Jason.Hoffman@PacifiCorp.com; CCameron@TEAinc.org; dbp@cpuc.ca.gov; mk1@cpuc.ca.gov; ayk@cpuc.ca.gov; cs6@cpuc.ca.gov; ed3@cpuc.ca.gov; jrg@cpuc.ca.gov; jmo@cpuc.ca.gov; jr5@cpuc.ca.gov; jmh@cpuc.ca.gov; mh3@cpuc.ca.gov; sha@cpuc.ca.gov; nc4@cpuc.ca.gov; rc5@cpuc.ca.gov; scl@cpuc.ca.gov; svn@cpuc.ca.gov; sb6@cpuc.ca.gov; sk8@cpuc.ca.gov; scr@cpuc.ca.gov; sc8@cpuc.ca.gov; ys2@cpuc.ca.gov; cxc@cpuc.ca.gov; dd4@cpuc.ca.gov; katharine.larson@energy.ca.gov; laura.mcwilliams@sen.ca.gov
Subject: R.17-06-026: PG&E's Compliance with D.18-10-019, OP 3

To All Parties in R.17-06-026:

Pursuant to Ordering Paragraph 3 of Decision 18-10-019, PG&E submits its version of the IOU Common Template for calculating the PCIA rate as a courtesy to the R.17-06-026 service list. The confidential version of the excel file attached will be provided to the CPUC Energy Division before the close of business today. Should you have any questions, please contact PG&E's case manager Tom Jarman (thomas.jarman@pge.com).

Josephine Wu | Case Coordinator | Pacific Gas and Electric Company | 77 Beale Street, Room 2364B | San Francisco, CA 94105
tel: 415.973.3414 | fax: 415.973.7131 | email: jwwd@pge.com |

Modified PCIA Workpaper Template

I. OVERVIEW

Decision (D.) 18-10-019 was approved in the Power Charge Indifference Adjustment (PCIA) Rulemaking (R.) 17-06-026 on October 11, 2018 (Final Decision). In the Final Decision, the Commission adopted revised inputs to the market price benchmarks (MPBs) that are used to calculate the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC). The revised methodology will be used to calculate the PCIA and CTC that take effect on January 1, 2019.

Among other things, Ordering Paragraph (OP) 3 of the Final Decision requires Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), collectively referred to as the Joint Utilities, to meet and confer to develop a uniform common spreadsheet template (Modified PCIA Workpaper Template, or Modified Template) for the calculation of PCIA rates and to submit the template to the Energy Division within ten days of the effective date of this order.

The starting point for the Joint Utilities' Modified Template is the PCIA Workpaper Template that was approved in D.17-08-026.[1] There are three primary changes adopted by D.18-10-019 that trigger revisions to the current common workpaper template:

(1) Revised inputs to the MPBs (OP 1 and OP 2),
(2) Adoption of the generation rate allocation factors (OP 4),
(3) True-up of billed revenues and actual costs which will be recorded to a new Portfolio Allocation Balancing Account (PABA) with vintaged subaccount accounts. (OP 7 and OP 8)

The impacts of these changes are summarized in Section II. A more detailed description of the modifications follows in Section III, Description of the Modified PCIA Workpaper Template. Finally, a list of the cells that have been intentionally left blank is provided in Section IV. The Joint Utilities note that certain elements adopted by the Final Decision, such as the PCIA cap, are not applicable in 2019 and are thus not yet reflected in the Modified Template.

The Joint Utilities also wanted to draw attention to the definition of the MPB as approved in D.18-10-019, Appendix 1, which includes the application of a line loss factor. The current format of the PCIA Workpaper Template approved in D.17-08-026 does not properly apply the line loss factor in the calculation of the market value and the net result introduces a slight error in the results.[2] The Joint Utilities requested in their comments on the APD that the line loss factor reflected in D.18-10-019, Appendix 1 be eliminated, among other things. Technically, a line loss factor does not need to be applied in the indifference calculation at all because the cost of the generation and the market value of the generation are the same whether you are measuring generation at the generator meter or at the customer meter. The Joint Utilities recognize that even though it was unopposed by any party, that the Final Decision did not address that proposal, so are incorporating the concept of a line loss factor in this template. SCE's and SDG&E's templates follow the calculation for line losses reflected in D.18-10-019, Appendix 1. In PG&E's template, PG&E has corrected the technical error that results from the current mismatch between the MWh and $/MWh for the line loss factor. The Joint Utilities are seeking guidance from Energy Division to address this error, but note that the difference between the two are immaterial.

---

1 This decision approved a Petition for Modification of D.06-07-030 that was submitted by PG&E, SCE, SDG&E and representatives of several CCAs to create a common PCIA calculation workpaper template for use in the Joint Utilities' respective ERRA Forecast proceedings.

2 In the Standard Workpaper template approved D.17-08-026, the line loss factor is applied to the non-renewable and renewable generation on the Total Portfolio Summary tab but it is not applied market value of the brown and green market price benchmark on the Indifference Amount Calculation tab and instead, the line loss is applied to the Portfolio Market Value on Line 25, which includes the value of Capacity. This introduces a slight error in the Market Value calculation.

The Joint Utilities note that the underlying forecast data reflected in the Modified Template are based on the assumptions used in each respective utility's initial 2019 Energy Resource Recovery Account (ERRA) Forecast Application filed in the first half of 2018, and are included for illustrative purposes only. Each utility will be filing an Update to its initial 2019 ERRA Forecast Application in early November 2018, based on updated forecast data and final MPB inputs provided by the Energy Division. As such, the rates shown in the Modified Template are strictly illustrative and will change upon implementation in January 2019.

Each utility is submitting to the Energy Division its version of the Modified Template that reflects necessary differences, including but not limited to IOU-specific ratemaking nomenclature, Transmission Access Charge area, rate groups, etc. However, the underlying formulas supporting the calculations are the same across the Joint Utilities.

II. SUMMARY

The Modified PCIA Workpaper Template is an excel workbook consisting of 5 tabs that present the total portfolio indifference calculation, resulting indifference amounts, and the calculation of the PCIA and CTC rates.

The revised inputs to the MPBs adopted in OP 5 trigger changes to 3 of the 5 public workpaper tabs that present the MPB inputs (Tab 2), summarize the Total Portfolio costs, generation, and capacity values (Tab 1), and calculate the indifference amount (Tab 3). Specifically, OP 3 adopts a Renewables Portfolio Standard (RPS) "green adder" that is based on aggregated data gathered from the Investor-Owned Utilities (IOUs), Community Choice Aggregators (CCAs), and Energy Service Providers (ESPs). This aggregated data and pricing will replace the current methodology, which required several inputs and a weighted-average calculation. Additionally, OP 3 replaces the previous single value used for the resource adequacy (RA) adder (which was derived from a California Energy Commission report) with an updated adder (which is derived from a CPUC report) that reflects three types of RA capacity: system, local, and flexible. Having three distinct RA product values requires that the portfolio composition detail the amount of system, local, flexible capacity in each of the vintaged portfolios.

OP 4 and Section 9.2 adopt the Joint Utilities' proposed rate design changes from their joint direct testimony (Exhibit IOU-1) to the revenue allocation factors and the billing determinants used to set the CTC and PCIA rates. The Modified Template reflects generation revenue allocation factors for the vintaged Indifference Amounts. Additionally, the rate calculation has been refined to divide the rate-group-level revenue requirements by the forecast vintaged rate-group-level sales.

OP 7 approves the Joint Utilities' proposed balancing account structure with subaccounts for each incremental vintaged portfolio to ensure that the costs, market revenues, and billed customer revenues are recorded to the appropriate subaccount. This requires a structural – but non-substantive -- change to the template to move from a "cumulative" presentation to an "incremental" presentation. The Joint Utilities note that the final CTC and vintaged PCIA rates reflected on the "Final PCIA and Generation Rates" tab continue to reflect the final cumulative rates that will appear on customers' bills.

The affected tabs and a brief description of the structural changes made are shown below:

1. IOU Total Portfolio Summary[3]

[3]SCE notes that in its August 31, 2018 response to a CalCCA data request in this proceeding, which requested a quantification of forecast 2019 PCIA rates under the then-pending Alternate Proposed Decision of Commissioner Peterman, SCE inadvertently categorized the output of its Utility-Owned Generation (UOG) Mountainview plant as "renewable," and thus valued its generation output at the Green MPB instead of the Brown Energy MPB. This inadvertent error understated the average forecast 2019 PCIA under the APD by about 5%. It is important to note (as the data request response did) that actual 2019 PCIA rates will be set in the Joint Utilities' respective 2019 ERRA Forecast proceedings, and will be based on forecasts set forth in their respective November Update testimonies in those proceedings. SCE has refined the confidential workpapers that support the data in the Modified

- Added line items to reflect System, Local, and Flex RA in the vintaged portfolios.

2. **Indifference Calculation Inputs**
   - Updated REC and Capacity market price benchmark line items and deleted line items that contained data supporting the prior methodology.

3. **Indifference Amount Calculation**
   - Expanded the capacity summary section to reflect System, Local, and Flex RA in the vintaged portfolios.
   - Expanded the "Capacity Market Value" section to reflect valuation for the three distinct product types.
   - Added PABA vintaged subaccount balance line item and updated naming convention for the summary "Indifference Amounts" to "Vintaged PABA Revenue Requirements."

4. **Indifference Rate Calculation**
   - Added vintaged Rate Group billing determinants to refine the rate calculation.
   - Present PCIA calculation incrementally first and show the cumulative results in the following line items.
   - Revenue allocator column name modified to reflect the source of the new revenue allocation factors.

5. **Final PCIA and Generation Rates**
   - Added system average rate line item.

The additions and changes on all tabs are shaded blue for easy identification.

III. <u>DESCRIPTION OF THE MODIFIED TEMPLATE</u>

1. **Vintage portfolios reflect the "incremental" vintage portfolios, rather than the "cumulative" vintage portfolios, as described generally on pages 4-53 and 4-54 of Joint IOU Exhibit 01** – Global change made to "IOU Total Portfolio Summary," "Indifference Amount Calculation," and "Indifference Rate Calculation" tabs.

   As noted in Joint IOU Exhibit 01, page 4-53:

   > For example, the [PABA] subaccounts will include a 2010 vintaged subaccount that will record the costs and market revenues of all [PCIA]-eligible generation contracts executed in the calendar year 2010 and the [PCIA]-eligible UOG approved by the Commission for cost recovery in 2010. Departing load customers who leave after July 2010 (*i.e.,* those with departing load customer vintage 2010 or later) and current bundled service customers are thus responsible for those costs. As such, they will be responsible for the net costs recorded in that 2010 subaccount and all "prior"…subaccounts, which…include the non-vintaged CTC, [PCIA]-eligible Legacy UOG, [and 2004-2009] sub-accounts.

   - "IOU Total Portfolio Summary" and "Indifference Amount Calculation" tab modified to reflect the "incremental" costs and attributes of each vintage portfolio. For example, the 2010 vintage portfolio *only* includes the costs and attributes of the resources executed in the calendar year 2010.

Template to more clearly delineate between renewable and non-renewable resources' forecast generation output. Those confidential workpapers will accompany the Modified Template, and will be submitted in each ERRA Forecast proceeding going forward.

- "Indifference Rate Calculation" tab modified to reflect the "incremental" vintage indifference amount allocated to each customer class.
    - PG&E: Rows 9-18
    - SCE: Rows 4-19
    - SDG&E: Rows: 3-9
- "Indifference Rate Calculation" tab modified to reflect the "incremental" indifference rate associated with each vintage subaccount.
    - PG&E: Rows 38-47
    - SCE: Rows 40-54
    - SDG&E: Rows 24-29
- "Indifference Rate Calculation" tab modified to reflect the final CTC and PCIA rates that will be reflected on customers' bills. For example, the "2010 PCIA" is the rate that a 2010 vintage customer would pay and is the sum of all of the "incremental" indifference rates for which they are responsible (i.e., Legacy UOG, 2004-2009, and 2010 incremental indifference rates).[4]
    - PG&E: Rows 53-62 and 67-76 (including DWR franchise fee)
    - SCE: Rows 57-72
    - SDG&E: Rows 34-39

2. **Modification to benchmarks and benchmark sources pursuant to Ordering Paragraph 1 – Changes made on "Indifference Calculation Inputs" tab, marked in light orange**
    - Removed lines related to the Resolution E-4475 method of determining the Green benchmark, and replaced with lines 6 and 7 on "Indifference Calculation Inputs" tab.
    - Added lines on "Indifference Calculation Inputs" tab to reflect different benchmarks for System, Local (by Transmission Access Charge Area), and Flexible RA.

3. **Modification to portfolio RA to reflect the three different RA products pursuant to Ordering Paragraph 1 and Section 6.2.1 – Changes made on "IOU Total Portfolio Summary" tab and "Indifference Amount Calculation" tab, marked in green**
    - Added lines to "IOU Total Portfolio Summary" tab to separately identify the total NQC, by RA product, in each vintaged portfolio. Pursuant to Section 6.2.1:
        - RA that provides both system and flexible capacity is counted as flexible capacity;
        - RA that provides both system and local capacity is counted as local capacity;
        - RA that provides system, local, and flexible capacity is counted as flexible capacity; and
        - RA that provides only system capacity is counted as system capacity.

      Additionally, the local capacity values shall be differentiated by Transmission Access Charge area.
    - Replaced lines related to the Resolution E-4475 method of determining the capacity adder, which only had one single RA value per vintage portfolio, with blue-shaded lines on "Indifference Amount Calculation" tab.

4. **Incorporation of the rate design changes described generally on pages 4-63 to 66 of Exhibit IOU-1 pursuant to Ordering Paragraph 4 and Section 9.2 – Changes made on "Indifference Rate Calculation" tab, marked in purple**
    - Cell B4 modified to note that the allocation of the PABA revenue requirement to customer classes would be determined using generation revenue allocation factors instead of the top 100 hours factors.
    - PG&E and SCE added vintage-specific forecast sales (also referred to as "billing determinants") in blue-shaded lines of the "Indifference Rate Calculation" tab, and divided the Vintage PABA revenue requirements by the vintage-specific billing determinants to calculate the CTC and PCIA rates listed in the "Incremental Rate for Each Portfolio of Resources" section (also shaded in blue). SDG&E's current factors for allocating its generation costs to bundled service customer groups are based on bundled service customer groups' load profiles. SDG&E does not currently have Commission-adopted

[4] *See also* footnote 94 of Joint IOU Exhibit-01, which states "Consistent with the Cost Recovery testimony included above, vintage [PCIA] rates will be determined using the [PCIA] subaccount revenue requirements. However, final [PCIA] rates listed on customers' bills will reflect one single [PCIA] rate component, which will be the sum of all of the incremental vintaged [PCIA] rates for which they are responsible.

generation allocation factors based on customer group load profiles at the system level. As such, under the Joint Utilities' proposal to apply consistent allocation factors, SDG&E will use its current generation allocation factors based on bundled service customer groups' load profiles to also allocate the relevant costs to its departing load customer until it proposes and the Commission adopts allocation factors based on customer groups' load profiles at the system level in a future GRC Phase II proceeding.

As explained on page 4-66 of Joint IOU Exhibit-01:

> Under the Current Methodology, the CTC and PCIA rate-group level [indifference amounts] are divided by the forecast rate group-level sales of all system customers. Continuing to use forecast system level kWh sales in the denominator used to set rates, as opposed to the forecast kWh sales of those responsible for each vintaged portfolio, will result in lower rates than are necessary to collect the revenue requirements. This would perpetuate a systemic undercollection bias in the balancing accounts because the rates are only applied to, and the revenues are only being collected from, those customers responsible for each vintaged portfolio.

Stated differently, a 2009 vintage departing load customer is not responsible for the 2018 vintage portfolio of resources, so that 2009 vintage departing load customer's usage should not be included in the forecast sales used to calculate the 2018 vintage PCIA. Including the forecast sales of the 2009 vintage departing load customers in the denominator used to set the 2018 vintage PCIA will result in a 2018 vintage PCIA rate that is set too low and a corresponding billed revenue deficiency,[5] or under-collection, in the PABA.

5. **Incorporation of the balance in the "PCIA cap balancing account" in the vintaged PCIA rate pursuant to Ordering Paragraph 9** – Change made on "Indifference Amount Calculation" tab, marked in blue
   - Added blue-shaded line to "Indifference Amount Calculation" tab to reflect balances in each vintage "PCIA cap balancing account" in the following year's rates.

6. **Incorporation of ratemaking changes pursuant to Ordering Paragraphs 6, 7, and 8 and described generally in Joint IOU Exhibit 01 Chapter 4 – Changes made on "Indifference Amount Calculation" tabs, marked in blue.**
   - Renamed "Final Indifference Amount" to "Vintaged PABA Revenue Requirement."
   - Added "PABA Year-End Balance" line to "Indifference Amount Calculation" tab to ensure that year-end balances in each vintage PABA sub-account are reflected in the following year's rates.

7. **Addition of a Pre-2002 "Legacy UOG" column pursuant to Conclusion of Law 12 – Changes made to "Total Portfolio," "IOU Total Portfolio Summary," "Indifference Amount Calculation," and "Indifference Rate Calculation" tabs in blue to separately identify costs and attributes of the Legacy UOG portfolio from the other vintaged portfolios.**[6]

8. **SCE Only - Addition of a "One-Time Refunds/Costs Applicable to All Customers" column – Changes made to "Indifference Amount Calculation" and "Indifference Rate Calculation" tabs in blue. Certain one-time refunds and/or costs are shared by all bundled service and departing load customers. Examples include DWR refunds and Energy Crisis-related costs and/or refunds for SCE**

5 For example, assume a PCIA revenue requirement of $10 and forecast system sales of 100 kWh. Additionally, assume 20 kWh of the system sales is not subject to the PCIA. Setting the PCIA rate at $0.10 ($10/100 kWh) will result in a systemic $2 under-collection because only 80 kWh is responsible for paying the rate ($0.10 x 80 kWh = $8). Instead, the PCIA revenue requirement of $10 should be divided by the forecast sales of those actually subject to the rate to set the final PCIA rate (*i.e.,* $10/80 kWh = $0.125).

6 *See also* footnote 81 of Joint IOU Exhibit 01, which states "Currently, pursuant to D.08-09-012, Legacy UOG is included in the overall cost responsibility of all customers who pay the PCIA. The Joint Utilities' proposal to track net costs in a separate subaccount of PABA does not modify that aspect of the Current Methodology."

pursuant to D.15-10-037. Such costs and/or refunds will be recorded to a separate sub-account of PABA and reflected in the final PCIA and generation rates.

9. **Other Enhancements and Modifications**
   - Total Portfolio tab modified to clearly delineate between Non-Renewable and Renewable Supply
   - Vintage-specific "system average rates" added to the "Final PCIA and Gen Rates" tab. These values are calculated by dividing the total vintage-specific PABA revenue requirement by the total vintage-specific billing determinants (all customer classes).

IV. LIST OF INTENTIONALLY BLANK CELLS

PG&E:

- IOU Total Portfolio Summary Tab, Cells D11 – Q12: Local and Flex RA in the Total Portfolio
- Indifference Calculation Inputs Tab, Cells D16 – D17: Local and Flex RA benchmarks
- Indifference Amount Calculation Tab, Cells F12 – S13, Local and Flex RA in the Total Portfolio
- Indifference Amount Calculation Tab, Cells F33 – S38, Local and Flex RA market value
- Indifference Amount Calculation Tab, Cells F49 – S49, DWR Revenue Requirement
- Indifference Amount Calculation Tab, Cells F50 – N50 and P50 – S50: One-Time Refunds/Costs Applicable to All Customers
- Indifference Amount Calculation Tab, Excel row 51: PABA Year-End Balance

SCE:

- IOU Total Portfolio Summary Tab, Cells D11 – P12: Local and Flex RA in the Total Portfolio
- Indifference Calculation Inputs Tab, Cells D16 – D17: Local and Flex RA benchmarks
- Indifference Amount Calculation Tab, Cells G48 – G49: One-Time Refunds/Costs Applicable to All Customers
- Indifference Amount Calculation Tab, Excel row 50: PABA Year-End Balance

SDG&E:

- PCIA Inputs Tab, Cells D13 – D14: Local and Flex RA benchmarks
- IOU Total Portfolio Summary Tab, Cells C19 – W20: Local and Flex RA in the Total Portfolio
- Indifference Amount Calculation Tab, Excel row 48: PABA Year-End Balance
- Indifference Amount Calculation Tab, Excel row 49: PCIA Cap Balancing Account Balance

Appendix D

From: Jarman, Thomas
Sent: Wednesday, October 31, 2018 7:00 PM
To: Christian_Lenci@Praxair.com; jeremy.weinstein@pacificorp.com; Mark.Byron@UCOP.edu; TLindl@kfwlaw.com; service@cforat.org; NMalcolm@MCEcleanEnergy.org; Ken@350BayArea.org; Jeanne.Sole@SanJoseCa.gov; SShupe@SonomaCleanPower.org; Danielle@RenewableEnergyStrat.com; CMKehrein@ems-ca.com; peffer@braunlegal.com; NSaracino@WEAWLaw.com; Blaising@BraunLegal.com; Blaising@BraunLegal.com; RL@eslawfirm.com; Tim@LargeScaleSolar.org; KMills@cfbf.com; Cynthia.Hansen@PacifiCorp.com; Saleba@EESConsulting.com; YLu@SanDiego.gov; ahoekstra@hanoverstrategyadvisors.com; Alia.Schoen@BloomEnergy.com; Brian.Theaker@NRG.com; RegRelCPUCCases <RegRelCPUCCases@pge.com>; Chris_King@Siemens.com; CHooven@sandiego.gov; Gutierrez, David <D1G9@pge.com>; diana.mahmud@gmail.com; DVawter@Terra-Gen.com; regulatory@ebce.org; EBeaver@SempraUtilities.com; EmilySangi@dwt.com; GChapjian@co.santa-barbara.ca.us; hanna.grene@energycenter.org; JCregar@co.santa-barbara.ca.us; Hilgart, Jessica <JKHh@pge.com>; KCameron@Buchalter.com; KatieJorrie@dwt.com; Kavya@NewsData.com; komidiji@semprautilities.com; Keith@KDWhiteConsulting.com; kjsimonsen@ems-ca.com; lettenson@nrdc.org; Laura.Genao@sce.com; lgoldberg@ebce.org; mk1@cpuc.ca.gov; Michelle.Stark@sce.com; NReardon@SonomaCleanPower.org; Paul@BarkovichAndYap.com
Subject: R.17-06-026, PG&E's Common Template REV1

To All Parties of Record in R.17-06-026:

Re: Revision to PG&E’s Common Template pursuant to D.18-10-019, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment.

In compliance with Decision 18-10-019 Ordering Paragraph (“OP”) 3 and subsequent direction from the CPUC’s Energy Division, today PG&E submitted a revision to the confidential version of PG&E’s uniform common spreadsheet template for calculation of the Power Charge Indifference Adjustment (“PCIA”) rates. The revised template replaces the version previously submitted on October 22, 2018 and is being provided as a courtesy to the R.17-06-026 service list in the attached excel titled “20181031_PGE_PCIA-OIR_Joint IOU Common Template_REV1.xlsx”.

The revised template includes two modifications:

1. IOU Total Portfolio Summary worksheet modification
On the “IOU Total Portfolio Summary” worksheet, PG&E correctly applied the Line Loss Adjustment Factor from Line 11 on the “Indifference Calculation Inputs” worksheet to calculate the CRS Eligible Non-Renewable Supply at Customer Meter (GWh) on Line 2 and CRS Eligible Renewable Supply at Customer Meter (GWh) on Lines 3. In the template submitted on October 22, 2018, PG&E used a different calculation method that showed slightly lower volumes.

2. Indifference Amount Calculation worksheet modification
On the “Indifference Amount Calculation” worksheet, PG&E modified the “Line Loss Adjusted Portfolio Market value” calculation on Line 26. This modification is consistent with PCIA Common Templates submitted by SDG&E and SCE and complies with the adopted calculation formula in D.18-10-019, Appendix 1. However, in making this required modification, PG&E is re-introducing a calculation error that PG&E sought to correct in its initial submission on October 22, 2018. This error exists in all three IOU versions of the template and in the adopted calculation formula in D.18-10-019, Appendix 1.

In the adopted calculation formula, D.18-10-019 defines Market Value (for vintage year, V) as:

Market Value = (Brown Energy x Brown Adder + RPS Energy x RPS Adder + NQC x RA Adder) x (LOSSES)

The Market Value formula scales up all three value components (Brown Energy, RPS Energy and RA value) by a line loss adjustment factor (LOSSES) so that the market value can be compared to CRS Eligible Portfolio Costs calculated at the generator meter. However, the line loss adjustment should only apply to the Brown Energy and RPS Energy components. Brown Energy and RPS Energy represent volumes measured at the customer meter, so it is appropriate to scale them up by the line loss adjustment. RA value calculated as NQC x RA Adder represents RA value at the generator meter, not the customer meter. Applying the line loss adjustment to the RA value overstates the RA value and incorrectly understates the indifference amount by approximately $22 million, based on the portfolio data and market price benchmarks included with the template.

All three IOUs identified this calculation error in the documentation that accompanied their respective template submissions on October 22, 2018. As previously requested, the Joint Utilities are seeking guidance from Energy Division on how to correct this error in the standard template.

Please let me know if you have any questions. Thank you.

NOTE: The recipient portion of this e-mail may not reflect all the addressees who are being served. The service list has been split into 50-addressee groups, to avoid rejection by CPUC and other e-mail servers.

Please also note that the PG&E's Regulatory Affairs Department does not maintain the official service list for Docket No. R.17-06-026. If you would no longer like to receive documents regarding this docket, please contact the CPUC Process Office directly via email at Process_Office@cpuc.ca.gov or by phone at 415-703-2021 to remove yourself from the official service list.

Appendix E

IOU Total Portfolio Summary

~~2019~~ XXXX ERRA ~~Revised~~ Forecast ~~- APD Analysis~~

							Vintage Portfolios								
Incremental by Year	**CTC-Eligible**	**Legacy UOG**	**~~Pre-2002~~**	**~~2004-~~2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
1. CRS Eligible Portfolio Costs ($000)															
2. CRS Eligible Non-Renewable Supply at Generator ~~Customer~~ Meter (GWh)															
3. CRS Eligible Renewable Supply at Generator ~~Customer~~ Meter (GWh)															
4. CRS Eligible Total Net Qualifying Capacity (MW)															
5. CRS Eligible System NQC (System only, No flex or local)															
6. CRS Eligible Local NQC (System and local, with or without flex)															
7. CRS Eligible Flexible NQC (System and flex only, No local)															

Indifference Calculation Inputs and Sources

~~2019~~ XXXX ERRA ~~Revised Forecast - APD Analysis~~

Line No.	Description	Source of Data	Value
1.	On Peak NP 15 Price ($/MWh)	Platt's	
2.	Off Peak NP 15 Price ($/MWh)	Platt's	
3.	On Peak Load Weight (%)	~~2016~~ XXXX Recorded Load - On Peak Hours	
4.	Off Peak Load Weight (%)	~~2016~~ XXXX Recorded Load - Off Peak Hours	
5.	Load Weighted Average Price ($/MWh)	Line 1 x Line 3 + Line 2 x Line 4	
6.	REC Benchmark ($/MWh)	~~Platt's (2019);~~ CPUC Energy Division ~~(2020 and beyond)~~	
7.	Total "Green" Benchmark ($/MWh)	Line 6 + Line 5	
8.	System RA Benchmark ($/kW-Year)	Energy Division	
9.	Local RA Benchmark ($/kW-Year)	Energy Division	
10.	Flexible RA Benchmark ($/kW-Year)	Energy Division	
~~11.~~	~~Line Loss Adjustment Factor~~	~~Resolution E-4475~~	
~~12.~~ 11.	Franchise Fees and Uncollectibles Factor	[GRC Decision / Advice Letter Reference]	

Indifference Amount Calculation

~~2019~~ XXXX ERRA ~~Revised~~ Forecast ~~- APD Analsysis~~

Line No.	Description	Equation	Unit	CTC-Eligible	Legacy UOG	~~Pre-2002~~	~~2004-~~2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Cost of Portfolio																
1.	CRS Eligible Portfolio Costs	Portfolio Summary Line 1	$000														
2.	CRS Eligible Non-Renewable Supply at Generator ~~Customer~~ Meter	Portfolio Summary Line 2	GWh														
3.	CRS Eligible Renewable Supply at Generator ~~Customer~~ Meter	Portfolio Summary Line 3	GWh														
4.	CRS Eligible System NQC	Portfolio Summary Line 5	MW														
5.	CRS Eligible Local NQC	Portfolio Summary Line 6	MW														
6.	CRS Eligible Flexible NQC	Portfolio Summary Line 7	MW														
7.	**Portfolio $/MWh Cost**	**Line 1 / (Line 2 + Line 3)**	**$/MWh**														
8.	**Market Value of Portfolio**																
9.	**Market Value of Brown Portfolio**																
10.	Non-Renewable Energy	Line 2	GWh														
11.	Platt's Weighted Price (Brown Benchmark)	Input Line 5	$/MWh														
12.	**Market Value of Brown Portfolio**	**Line 10 x Line 11**	**$000**														
13.	**Market Value of Green Portfolio**																
14.	Renewable Energy	Line 3	GWh														
15.	Weighted Average Green Benchmark	Input Line 7	$/MWh														
16.	**Market Value of Green Portfolio**	**Line 14 x Line 15**	**$000**														
17.	**Capacity Adder**																
18.	Average Monthly System NQC	Line 4	MW														
19.	System RA Benchmark	Input Line 8	$/kW-Year														
20.	Average Monthly Local Area NQC	Line 5	MW														
21.	Local RA Benchmark	Input Line 9	$/kW-Year														
22.	Average Monthly Flexible NQC	Line 6	MW														
23.	Flexible RA Benchmark	Input Line 11	$/kW-Year														
24.	**Market Value of Capacity**	**Sum (Lines 18 x 19, 20 x 21, 22 x 23)**	**$000**														
25.	**Portfolio Market Value**	**Line 12 + Line 16 + Line 24**	$000														
~~26.~~	~~**Line Loss Adjusted Portfolio Market value**~~	~~**(Line 12 + Line 16) / (1-Input Line 11) + Line 24**~~	~~$000~~														
26.	**Indifference Amount**																
27.	**Portfolio Total Cost**	**Line 1**	$000														
28.	**Portfolio Market Value**	**Line 25~~26~~**	$000														
29.	**Total Indifference Amount (Unadjusted)**	**Line 27~~28~~ - Line 28~~29~~**	$000														
30.	**DWR Revenue Requirement**		$000														
31.	**One-Time Adjustments (if applicable)**[1/]		$000														
32.	**PABA Year-End Balance**		$000														
33.	**Vintaged PABA Revenue Requirement**	**Sum (Lines 29~~31~~:32~~33~~)**	$000														
34.	**Vintaged PABA Rev Req with FF&U**	**Line 33~~34~~ x Input Line ~~12.~~ 11.**															

These lines are renumbered accordinly

1/ One-Time Adjustment - Note to provide detail

Indifference Rate Calculation

~~2019~~ XXXX ERRA ~~Revised~~ Forecast ~~- APD Analsysis~~

			CTC RRQ	Indifference Amount w/o CTC Allocated to Rate Group -- Total Indifference RRQ by Vintage x Column C											
Rate Group	Total Billing Determinants (kWh)	Generation Allocation	All	Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Ongoing			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BA Amortization															
Total RRQ															
Residential															
Small L&P															
Medium L&P															
E19															
Streetlights															
Standby															
Agriculture															
E20 T															
E20 P															
E20 S															
Total	-														

Rate Group	Forecast Sales of Those Responsible for Each Portfolio of Resources (GWh)												
	CTC Sales	**Legacy UOG**	~~2002~~ **2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Residential													
Small L&P													
Medium L&P													
E19													
Streetlights													
Standby													
Agriculture													
E20 T													
E20 P													
E20 S													
Total Sales													

	CTC Rate	Incremental Rate for Each Portfolio of Resources (Vintage Indifference Amount by Rate Group / Forecast Sales by Rate Group)											
Rate Group	**All**	**Legacy UOG**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Residential													
Small L&P													
Medium L&P													
E19													
Streetlights													
Standby													
Agriculture													
E20 T													
E20 P													
E20 S													
Total													

Indifference Rate Calculation

~~2019~~ XXXX ERRA ~~Revised~~ Forecast ~~- APD Analsysis~~

	CTC Rate	Cumulative Rate for Each Portfolio of Resources (Vintage Indifference Amount by Rate Group / Forecast Sales by Rate Group)										
Rate Group	**All**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Residential												
Small L&P												
Medium L&P												
E19												
Streetlights												
Standby												
Agriculture												
E20 T												
E20 P												
E20 S												
Total												

DWR Franchise Fee (All) = $ 0.00004

	CTC Rate	Cumulative PCIA Rate with DWR Franchise Fee										
Rate Group	**All**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Residential												
Small L&P												
Medium L&P												
E19												
Streetlights												
Standby												
Agriculture												
E20 T												
E20 P												
E20 S												
System Average Rate												

Rate Model - Check	PG&E Rates from Billing Table												
Rate Group	**CTC**	**Legacy UOG**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Residential													
Small L&P													
Medium L&P													
E19													
Streetlights													
Standby													
Agriculture													
E20 T													
E20 P													
E20 S													

	Difference											
Rate Group	**CTC**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Residential												
Small L&P												
Medium L&P												
E19												
Streetlights												
Standby												
Agriculture												
E20 T												
E20 P												
E20 S												

Note: Difference +/- of $0.00001 / kWh is due to rounding.

Cost Responsibility Surcharge (CRS) Rates

~~2019~~ XXXX ERRA ~~Revised~~ Forecast ~~- APD Analsysis~~

Rate Group	DWR Bond (All Vintages)	ECRA (All Vintages)	CTC (For All Vintages)	Proposed PCIA Rates by Vintage 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential														
Small L&P														
Medium L&P														
E19														
Streetlights														
Standby														
Agriculture														
E20 T														
E20 P														
E20 S														
System Average PCIA Rate by Vintage														

Appendix F:
Declaration

DECLARATION OF DONNA BARRY

I, Donna Barry, declare as follows:

1. I am a Principal Regulatory Analyst, employed by Pacific Gas. and Electric Company ("PG&E"). My business address is Pacific Gas and Electric Company, 77 Beale Street, Room 1321, San Francisco, CA 94105.

2. Pursuant to Rule 16.4 of the California Public Utilities Commission ("Commission") Rules of Practice and Procedure, this declaration provides support for facts supporting the Petition to Petition for Modification of Decisions (D.) 17-08-026 and 18-10-019 filed by PG&E, Southern California Energy Company, and San Diego Gas & Electric Company (the "Joint Utilities").

3. Unless stated otherwise, I have personal knowledge of the facts set forth in this declaration and the Petition for Modification of Decisions (D.) 17-08-026 and 18-10-019 (the "Petition") filed by the Joint Utilities and I would competently testify to them if called to do so.

4. In D. 17-08-026, the California Public Utilities Commission adopted a Template used by the Joint Utilities to calculate the Power Charge Indifference Adjustment ("PCIA") charge. The Template contains multiple tabs with an inconsistent application of the line loss factor, including the application of line losses to the resource adequacy ("RA") Market Value of capacity for the PCIA-eligible resources.

5. In D. 18-10-019, the California Public Utilities Commission adopted Appendix 1, that defines the calculation for the PCIA Market Price Benchmark (MPB) for a vintage portfolio and the Market Value of the PCIA-eligible portfolio, by vintage. As part of the Commission's

adopted calculations, line losses apply to the RA Adder and the RA Market Value of PCIA-eligible resources.

6. Application of line losses to the RA Adder and RA Market Value of PCIA-eligible resources is in error because the RA is a capacity product and as such, the RA Adder and RA Market Value is not impacted by line losses. RA is calculated as the Net Qualifying Capacity (NQC) of a resource and has no line loss component. Applying a line loss factor to the RA Adder and RA Market Value is incorrect and introduces errors to the PCIA calculation.

7. In addition to the error in Appendix 1 of D.18-10-019, the application of the line loss factor to the RA Market Value is also embedded in the PCIA Template approved in D.17-08-026. In addition, the PCIA Template presents non-renewable and renewable generation at the customer meter while the capacity volumes are at the generator. To determine generation at the customer meter, the template scales output at the generator down by a factor of 1 minus the line loss (which is mathematically correct) to represent generation at the customer meter and grosses the final market value back up by a factor of 1 plus the line loss, which is mathematically incorrect. As a result of these inconsistencies, the calculation of the portfolio market value is inaccurate.

8. As a result of the errors introduced by applying line losses to the RA Adder and RA Market Value in the PCIA Template and Appendix 1 to D. 18-10-019, PCIA rates are set lower than they would be without the calculation error, which has the effect of creating a systematic under-collection in the Portfolio Allocation Balancing Account. Ultimately, customers will pay for the resulting under-collection through the true-up of the PCIA charge, however, the systemic error adds year-to-year volatility to the PCIA rates. Correction of line loss errors will eliminate the systematic PCIA under-collection and, ultimately, rate volatility for all customers.

9. As detailed in the Joint Utilities' Petition, PG&E identified the Template error following the issuance of D. 17-08-026. PG&E first identified the Template error presented by this Petition as part of its 2018 Energy Resource Recovery Account ("ERRA") Forecast proceeding's November Update, filed in November 2017. PG&E proposed a method to correct the misapplication of line losses in its November Update submittal however, at the request of Energy Division, PG&E was asked to resubmit the PCIA Template workpapers using the PCIA template as approved in D.17-08-026. PG&E filed a conforming PCIA workpaper using the Template format approved in D.17-08-026. PG&E's original proposal to fix the line loss error was not adopted as part of the Commission's disposition its 2018 ERRA Forecast.

10. Following PG&E's 2018 ERRA Forecast Proceeding, PG&E sought to correct the Template error introduced by D. 17-08-026 and the error introduced by Appendix 1 to D. 18-10-019 as part of Rulemaking (R.) 17-06-026 concerning the Power Charge Indifference Adjustment. The Joint Utilities Petition contains citations to the record in R. 17-06-206 supporting PG&E's corrective efforts. Attached to the Petition are true and correct copies of PG&E's 2018 communications to the Commission, served to parties to R. 17-06-026 identifying Template errors and estimating the departing load under-collection caused by such errors.

11. In D. 20-03-019, the Commission determined a Petition to Modify the applicable decisions is the proper vehicle to resolve errors related to the application of line losses to the PCIA calculation.

12. The Joint Utilities proposal to eliminate the line loss factor completely from the calculations provided in Appendix 1 to D. 17-08-026 and Appendix 1 to D. 18-10-019 will resolve the errors associated with the application of line losses to PCIA-eligible capacity. Generation-metered volumes would be used directly to calculate market value, instead of employing the Template's current two-step approach of using customer-metered volumes to

calculate the market value and then grossing up the market value by a line loss factor. Direct use of the generation-metered volumes eliminates the two errors and simplifies the Template. Generation-metered volumes for PCIA-eligible resources are available as part of Joint Utilities' ERRA Forecast applications.

13. The modifications proposed by the Joint Utilities in Appendix A and Appendix B to this Petition will correct the error introduced by applying line losses to capacity and the inconsistent gross-up and gross-down of energy values, correcting the calculated market value for the PCIA calculations.

I declare under penalty of perjury, under the laws of the State of California, that all statements contained in this Declaration are true and correct.

Executed this 7th day of August 2020, in San Francisco, California.

____*/s/ Donna Barry*____________

Donna Barry